Nebraska Public Power District
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Joe L. Citta, Jr.
Corporate Environmental Mgr.
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March 15, 2011

Ms. Shelley Schneider
Air Administrator, Air Quality Division
Nebraska Department of Environmental Quality
Suite 400, The Atrium
1200 N Street
Lincoln, NE 68509-8922

Subject: Nebraska Public Power District, Gerald Gentleman Station, Units 1 & 2, Sutherland, NE Supplemental BART Assessment – Dry Sorbent Injection (DSI) and Dry Sorbent Injection Cost Analysis for Gerald Gentleman Station

Dear Ms. Schneider:

In response to the Nebraska Department of Environmental Quality's (NDEQ) request in the telephone call of February 15, 2011, enclosed is the Supplemental BART Assessment evaluating the potential applicability of Dry Sorbent Injection (DSI) technology for control of sulfur dioxide (SO_2) emissions as part of the Best Available Retrofit Technology (BART) requirements for Gerald Gentleman Station (GGS) Units 1 & 2. This submittal was prepared under severe time constraints due to the need to meet the NDEQ's necessary response date and, therefore, it is not as refined or detailed as the prior analyses of other technologies in NPPD's 2008 BART Analysis Report.

This analysis concludes that DSI is not as cost effective as dry or wet Flue Gas Desulfurization (FGD) on a cost per deciview basis, which is the first reason it should be ruled out as a BART option. The primary component of annualized cost for DSI technology is the relatively high costs of the selected sorbent (Trona). Compounding this is the very high uncertainty in how effective DSI could be on GGS Units 1 & 2. Most of the applications of DSI have been for control of sulfur trioxide (SO_3) emissions and resulting "blue plume" issues, using much lower sorbent injection rates than would be needed to attempt a high level of SO_2 control. Given the lack of implementation of DSI technology on boilers in this size range for SO_2 control, and without prior GGS specific modeling and testing, attempting to use the technology for GGS would truly constitute a demonstration project. This is a second reason why DSI should be ruled out as a BART option.

If you have any questions regarding the enclosed Supplemental BART Assessment, including dispersion modeling, prepared by HDR Engineering, Inc., or the enclosed Dry Sorbent Injection Cost Analysis prepared by Sargent & Lundy, please do not hesitate to contact me at (402-563-5355).

Sincerely,

Joe L. Citta, Jr.
Corporate Environmental Manager

Att.: BART Analysis of DSI, including dispersion modeling on CD

cc: Mike Linder, NDEQ w/o cd
Jay Ringenberg, NDEQ w/o cd
Brad Reid, NDEQ w/cd

bc: Dave Sloat, Sargent & Lundy w/o cd
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Nebraska Public Power District, Gerald Gentleman Station, Units 1 & 2, Sutherland, NE

Supplemental BART Assessment – Dry Sorbent Injection (DSI)

INTRODUCTION

In February 2011 the Nebraska Department of Environmental Quality (NDEQ) requested that Nebraska Public Power District (NPPD) supplement the 2008 BART Analysis for Gerald Gentleman Station (GGS) Units 1 & 2. The 2008 BART Analysis considered various technologies for the control of nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions. The BART determination of NDEQ contained in the December 2010 draft Nebraska Regional Haze SIP is that BART for these emission units is the application of low-NOx burners and overfire air (LNB/OFA) to meet an average (of both units) NO_x emission limit of 0.23 pounds per million British thermal units (lb/MMBtu) of heat input, and continued use of low sulfur coal with respect to SO_2 emissions, without installation of post-combustion controls.

NDEQ has requested that NPPD perform an analysis of DSI in a "side-by-side" comparison against dry and wet flue gas desulfurization (FGD) systems, which were evaluated in the 2008 BART Analysis. Because the possible implementation timing of SO_2 emission control retrofits for any of these technologies would be farther in the future than originally assessed, NPPD requested Sargent & Lundy to perform the cost analysis for a hypothetical implementation of DSI in the year of 2016 (see attached Appendix A, Dry Sorbent Injection Cost Analysis for Gerald Gentleman Station, prepared by Sargent & Lundy, March 11, 2011). Sargent & Lundy has escalated the earlier costs for dry and wet FGD to the year 2016, and also used 2016 for DSI cost estimation, to provide the most reasonable side-by-side comparison of the various control technologies. HDR has used the Sargent & Lundy cost estimates, together with CALPUFF dispersion modeling results for visibility improvement with DSI, to calculate the costs per amount of visibility improvement to allow a comparison of DSI with both dry and wet FGD technologies assessed in the 2008 BART Analysis.

BART ANALYSIS – DRY SORBENT INJECTION

As with the 2008 BART Analysis, and as directed by BART implementation guidelines for control of Regional Haze (Appendix Y to 40 CFR 51), this analysis of DSI proceeds in a five-step process, as follows:

STEP 1—Identify All Available Retrofit Control Technologies,

STEP 2—Eliminate Technically Infeasible Options,

STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,

STEP 4—Evaluate Impacts and Document the Results, and

STEP 5—Evaluate Visibility Impacts.

STEP 1—Identify All Available Retrofit Control Technologies

This step is fairly obvious for the current analysis, as NPPD has been asked to assess just one additional control technology for SO_2 emissions control, that being DSI. However, the BART guidelines state that:

> *"In identifying "all" options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving."*

This is a challenging aspect of the current DSI evaluation, because the technology has not been applied on similar units such that we can have confidence in knowing what "maximum level of control" to assume for the technology. On the one large boiler proposed for DSI application, a unit rated at 584 MW at the Boardman Power Plant in Oregon, the applicant proposed DSI implementation to bring emissions down from 0.6 lb/MMBtu to 0.4 lb/MMBtu (33% reduction), and requested flexibility to revise the final SO_2 emission rate depending on the success of pilot testing. Also, as discussed in the more detailed technical assessment provided by Sargent & Lundy (see Appendix A), the temperatures in the ductwork where sorbent could be injected on GGS Units 1 & 2 are not optimum, which would make it more difficult to achieve high SO_2 removal rates.

Given the great uncertainty in applying DSI for the first time at a large coal-fired boiler, this analysis has identified a theoretical controlled emission rate of 0.36 lb/MMBtu, which would equate to nearly 80% control for the design basis coal used for the FGD analysis in the 2008 BART Analysis. The 0.36 lb/MMBtu emission rate being assessed here is slightly more aggressive than in the Boardman Power Plant DSI BART Analysis, and for the reasons stated above and in Appendix A, may be quite optimistic given the lack of demonstration of DSI on boilers of this size and type.

By using the emission rate of 0.36 lb/MMBtu for this DSI analysis, NPPD is not committing to this number as a potential permit limit. This is only being used as a potential control level to produce an estimate of the costs and resultant impacts for DSI implementation. Given the uncertainties, it would take a significant amount of GGS-specific facility modeling and testing studies accompanied by enforceable contractual vendor performance guarantees to be confident about meeting any particular emission rate.

STEP 2—Eliminate Technically Infeasible Options

Based on lack of DSI implementation on similar sized PRB-fired coal boilers, NPPD's engineering consultant, Sargent & Lundy considers DSI not "technically feasible" as defined under the BART guidelines. In its discussion of technical feasibility under the BART guidelines, EPA states:

> *Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, we do not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an*

> *emissions limit is technically infeasible. Generally, you should make decisions about technical feasibility based on chemical, and engineering analyses (as discussed above), in conjunction with information about vendor guarantees.*

NPPD does not have a contractual emissions performance guarantee from any vendors of DSI technology. Obviously, such a vendor has much to gain in sorbent sales if their technology is implemented successfully, but also has much to lose if a guarantee cannot be met, and will be reluctant to make such a guarantee without substantial pilot studies on units of similar size and characteristics to the units being considered for controls. Given the fact that DSI for control at any given outlet emission rate has not been demonstrated on a unit similar to GGS Unit 1 & 2, Sargent & Lundy considers DSI to be an undemonstrated technology for these units at this time. However, because of the NDEQ request that NPPD evaluate DSI as if it were a technically feasible control option for GGS, NPPD is carrying the DSI technology evaluation (assuming 0.36 lb/MMBtu outlet SO_2 emissions) through the final three steps of the BART analysis as described below.

STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies

In this case, the only additional technology being evaluated is DSI. Step 3 involves evaluating the potential control effectiveness of the technology or technologies being considered. EPA expresses in the BART guidelines that the control level should be specified in a metric that relates to the process rate or product produced, which in the case of boilers is typically specified in units of lb/MMBtu. In this case, we have limited information to provide a basis for establishing a control level as discussed earlier. Thus, to present the comparison requested by NDEQ, and based on both a similar control level used in the Boardman Power Plant DSI BART analysis, and a very aggressive removal rate for GGS, an SO_2 control level of 0.36 lb/MMBtu has been selected for this analysis.

STEP 4—Evaluate Impacts and Document the Results

The fourth step in the BART analysis evaluates A) costs of compliance, B) energy impacts, C) non-air quality environmental impacts, and D) remaining useful life.

With respect to "remaining useful life," this factor is considered only if the source unit(s) being evaluated have a relatively short life until expected permanent shutdown, such that a typical amortization period for control equipment (e.g., 10-20 years) means that BART controls would not be useful for at least a normal amortization period. In this case, both GGS units are expected to have a long enough operating future such that remaining useful life does not affect the BART cost analysis.

In the case of potential DSI application to GGS Units 1 & 2, factors A), B) and C) above have all been assessed by Sargent & Lundy (see Appendix A) in terms of their effects on potential costs to NPPD. The costs of compliance are calculated for both capital expenditures to install the DSI technology and supporting infrastructure (rail spur, sorbent tanks, larger ash/waste handling tanks, landfill, etc.) and for operation and maintenance (O&M) costs. In the case of DSI, the major O&M cost is the sorbent itself, which is estimated to cost $145/ton delivered to the site. A side-by-side summary of the year 2016 annualized capital cost, annualized O&M, and total annualized costs for dry FGD, wet FGD, and DSI are provided in Table 1.

Table 1 also summarizes estimated costs in terms of dollars per ton of pollutant removed. The amounts of pollutants removed are theoretical values based on a 100% capacity factor for both of the units and assuming that the baseline emissions are equal to the maximum 24-hour SO2 emission rate of both units combined in the 2001-2003 period specified by NDEQ for the purpose of ensuring consistent BART analysis across all sources (see 2008 BART Analysis on-file with NDEQ).

Table 1. Comparison of Annualized Costs for SO_2 Emission Controls in 2016 (Combined GGS Units 1 and 2)

Cost Element	Dry FGD	Wet FGD	DSI
Total Capital Cost	\$1,057,068,000	\$1,109,003,000	\$208,330,000
Annualized Capital Cost	\$86,166,000	\$90,422,000	\$17,500,000
Annualized O&M Cost	\$30,697,000*	\$26,368,000	\$138,270,000
Total Annualized Cost	\$116,863,000	\$116,790,000	\$155,770,000
Annual Tons SO_2 Removed	39,815	39,815	25,857
Cost Per Ton Removed	\$2,935	\$2,933	\$6,024

*Includes annual outage cost of \$752,000

The energy consumption required by the DSI system is not a large percentage of plant output, so it is not expected to require substantial replacement generation. However, the energy aspect of this analysis tallies only the in-plant energy use, and does not attempt to add up the energy used in mining the sorbent (Trona), transporting it to the facility by rail, land-filling the additional waste product, or obtaining replacement material for the coal ash product currently being consumed for beneficial reuse. The energy costs for off-site Trona production and delivery activities are inherent in the delivered cost of the sorbent at the site.

The non-air environmental impacts are primary due to construction and operation of an additional landfill that would be needed to hold the new waste product. In addition to the Trona-related mass of waste, the ash that is currently sold from GGS would represent not only lost revenue to NPPD, but additional cost for landfill space.

STEP 5—Evaluate Visibility Impacts.

The visibility impacts analysis is based on the same CALMET/CALPUFF modeling system and software version numbers, and the same modeling protocol approved for the 2008 BART Analysis for GGS and other BART-related modeling in Nebraska. HDR executed the CALPUFF model and post-processors for the DSI scenario, assuming baseline emissions of NO_x and PM components, and using an SO_2 emission rate based on an emission factor of 0.36 lb/MMBtu and at maximum permitted heat input rate.

The DSI technology would not be expected to significantly alter stack exhaust parameters, so these were kept the same as for the baseline scenario for input to CALPUFF. An updated table of emission rates and stack parameters with the DSI scenario added is included as Appendix B of this document.

To provide the visibility impact modeling results in a format that is most convenient for NDEQ use, we have copied the tabular summary of SO_2 BART control options and modeling results from Table 10.14 of the draft December 2010 NDEQ State Implementation Plan for Regional Haze and Best Available Retrofit Technology (BART) at the end of this section. We have edited that table to insert the DSI control option and the CALPUFF modeling results. We have also calculated the cost benefit metric in units of dollars/year/change in deciviews ($/yr/ΔdV). All the edits to Table 10.14 for addition of the DSI option and for clarifying the data are shown in gray highlights in the edited table and its footnotes provided at the end of this section.

Both NPPD and HDR are not clear on how the NDEQ has calculated the "Cost per Day of Improvement" metric in Table 10.14 of the draft SIP, so we have left this blank.

The average (across three years of modeled meteorology) cost/benefit metric, or cost effectiveness measured as $/yr/Δdv, is presented in Table 2 for dry sorbent injection (DSI) of Trona with SO_2 controlled to 0.36 lb/MMBtu, and for the two controlled emission levels (0.15 lb/MMBtu and 0.10 lb/MMBtu) with wet flue gas desulfurization (FGD), updated to year 2016 annualized costs. Note that the estimated annualized costs for dry FGD are virtually the same as for wet FGD at the same control levels, so just the wet FGD values are presented here.

Table 2. Average Cost Effectiveness Comparison for SO_2 Controls

Control Technology	Controlled Emissions Level (lb/MMBtu)	Average Incremental Impairment Improvement Cost ($/yr/ΔdV)
DSI	0.36	$ 287,764,058
FGD (wet)	0.15	$ 154,504,368
FGD (wet)	0.10	$ 142,860,500

Table 10.14: Incremental Visibility Effectiveness (SO_2 Controls)

Control Option	Class I Area with Greatest Impact from GGS	2001 Badlands	2002 Badlands	2003 Badlands
Baseline (no SO_2 Control)	SO_2 Modeled Emission Rate (lb/MMBtu)	0.749	0.749	0.749
	Modeled 98th Percentile Value (dV)	2.845	2.828	3.121
	Number of Days Exceeding 0.5 dV	54	55	60
DSI Control Added (0.36 lb/MMBtu)	Modeled 98th Percentile Value (dV)	2.158	2.409	2.540
	Incremental Visibility Impairment Improvement (ΔdV) [1]	0.696	0.419	0.581
	Number of Days Exceeding 0.5 dV	43	44	44
	Incremental Impairment Improvement Cost ($/yr/$\Delta$dV)[1],[3]	$223,807,472	$371,766,110	$268,106,713
	Cost per Day of Improvement			
FGD Control Added (0.15 lb/MMBtu)	Modeled 98th Percentile Value (dV)	1.836	2.125	2.478
	Incremental Visibility Impairment Improvement (ΔdV) [1], [4]	1.009	0.703	0.643
	Number of Days Exceeding 0.5 dV	36	35	39
	Incremental Impairment Improvement Cost ($/yr/$\Delta$dV)[1]	$115,748,266	$166,130,868	$181,633,971
	Cost per Day of Improvement	$3,442,603	$3,543,963	$3,177,787
FGD Control Added (0.10 lb/MMBtu)	Modeled 98th Percentile Value (dV)	1.790	2.026	2.443
	Incremental Visibility Impairment Improvement (ΔdV) [1], [4]	1.055	0.802	0.678
	Number of Days Exceeding 0.5 dV	33	33	36
	Incremental Impairment Improvement Cost ($/yr/$\Delta$dV)[1],[2]	$110,701,422	$145,623,441	$172,256,637
	Cost per Day of Improvement	$3,755,566	$3,755,566	$3,442,603

[1]Total annualized cost & incremental visibility impairment improvement compared to baseline.

[2] The control can be achieved without additional costs, so total annualized cost/the overall incremental impairment improvement is calculated.

[3]Total annualized cost (capital + O&M) of DSI estimated at $155,770,000.

[4]Total annualized costs (capital + O&M) of FGD ("wet" shown here) control options were updated to year 2016 annualized values to calculate the "Incremental Impairment Improvement Cost" for each year of modeling. This cost is estimated at $116,790,000/yr for both wet FGD at 0.15 lb/MMBtu and wet FGD at 0.10 lb/MMBtu (difference is insignificant). Therefore, the annualized cost for the 0.15 lb/MMBtu wet FGD option is conservatively used in the calculations for both the 0.15 and 0.10 lb/MMBtu FGD options.

CONCLUSIONS

Based on the side-by-side comparison of SO_2 emission control with DSI technology to both dry and wet FGD, which were analyzed in the 2008 BART Analysis for GGS Units 1 & 2, it is clear that DSI has substantially higher costs per amount of visibility improvement. Added to this is the great uncertainty in the ability of DSI to remove SO_2 emissions at any specified control level, and it is concluded that DSI can not be considered as BART for GGS Units 1 & 2.

APPENDIX A

Sargent & Lundy LLC

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March 11, 2011
Project No. 12681-002

Dry Sorbent Injection Cost Analysis for
Gerald Gentleman Station

Mr. Joseph L. Citta, Jr.
Corporate Environmental Manager
Nebraska Public Power District
1414 15th Street, P. O. Box 499
Columbus, NE 68601

Dear Joe:

As stated in my previous letter (January 6, 2011), it remains S&L's judgment that the DSI technology has not been proven on any power plant the size of the GGS units and, therefore, should not be considered "technically feasible" as the term is defined in the Regional Haze rule. Even so, as requested by NPPD, S&L developed the cost estimates for the application of the DSI technology on both GGS units to be as close to a side-by-side comparison to the previously analyzed dry and wet FGD technologies as is practical and reasonable.

Although the initial capital requirement for a DSI system at GGS is considerably less than that required for either of the FGD technologies evaluated in the 2008 BART Analysis, the operating costs for the DSI system at GGS, over the 20 year amortization life, resulted in an annualized cost of nearly 34% greater for the DSI system. Also, the cost to capture a ton of SO_2 with the DSI system is over twice as expensive as that required with either of the FGD technologies evaluated in the 2008 BART Analysis.

The report with the subject title is attached.

Yours very truly,

William DePriest
Senior Vice President and
Director, Environmental Services

WD/jvk
Attachment
Copies:
J. M. Meacham
P. Hoornaert
D. G. Sloat

Dry Sorbent Injection Cost Analysis for Gerald Gentleman Station

1.0 Introduction

Gerald Gentleman Station (GGS) is a source subject to the Regional Haze rule. A Best Available Retrofit Technology (BART) Analysis was submitted to the Nebraska Department of Environmental Quality (NDEQ) in February 2008 (hereafter referred to as 2008 BART Analysis) which included an evaluation of retrofitting emissions control technologies to lessen the impact of Gerald Gentleman Station (GGS) on visibility at the Badlands National Park in South Dakota. The technologies considered in the 2008 BART Analysis were dry and wet Flue Gas Desulfurization (FGD) systems for SO_2 control and Low NO_x burners (LNB) and Selective Catalytic Reduction (SCR) for NO_x control. Sargent & Lundy (S&L) provided input to the 2008 BART Analysis by providing capital, O&M, and annualized cost estimates for the FGD and SCR technologies.

The 2008 BART Analysis did not include an evaluation of Dry Sorbent Injection (DSI) technology because it was not considered to be technically feasible for use at GGS. During the final comment period for the associated Nebraska State Implementation Plan (SIP) in 2010, the NDEQ received comments from the National Park Service suggesting that dry sorbent injection should be considered for application at GGS. At Nebraska Public Power District's (NPPD's) request, Sargent & Lundy prepared a letter dated January 6, 2011 that responded to the National Park Service comments. In that letter, Sargent & Lundy delineated the considerations that were used to eliminate DSI from being addressed in the 2008 BART Analysis and concluded that "DSI is currently not technically feasible for application for the source under consideration, Gentleman Station Units 1 and 2", and that "while … an argument could be made that DSI is available for certain source type applications, it is not applicable to Gentleman Station".

The NDEQ disagreed with S&L's conclusion. In February 2011, the NDEQ asked that a side-by-side comparison be performed of dry sorbent injection technology and the FGD technologies, including both a cost comparison and a visibility impact comparison. Although S&L still believes that DSI is not technically feasible as previously stated in our January 6, 2011 letter, as requested by NPPD, we proceeded to prepare the cost comparison, for what should be considered a hypothetical evaluation based on S&L's opinion of the "technical feasibility" of the DSI technology.

As detailed herein, this analysis identifies the hypothetical capital, O&M, and annualized costs of applying dry sorbent injection technology at GGS. The analysis is based on both publicly available data and S&L expertise related to DSI. The visibility improvement and effectiveness will be modeled by HDR. HDR performed the same modeling used in the 2008 BART Analysis.

2.0 Evaluation Methodology

The evaluation of DSI technology for the purpose of developing cost estimates for SO_2 reduction at GGS was based on the following:

- Selection of a "target" stack SO_2 emission rate
- Selection of a sorbent type for reduction of SO_2
- Selection of a sorbent stoichiometric ratio based on the SO_2 removal efficiency needed

Once the appropriate performance parameters were established, design of the system could be approximated and the sorbent consumption and waste production rate could be calculated. The capital and O&M costs could then be determined. The final step was to convert the capital and O&M costs into an annualized cost estimate such that the technologies could be compared on an equal basis. This approach is further explained in the following sections.

2.1 Selection of "Target" Stack SO_2 Emission Rate

DSI technology has demonstrated the capability of removing moderate amounts of SO_2. However, DSI has not demonstrated that it can remove as much SO_2 as conventional wet or dry utility grade FGD technologies. In the 2008 BART Analysis, the candidate FGD technologies (conventional wet limestone and lime spray dryer) were evaluated as being able to reduce SO_2 emissions to less than 0.15 lb/MMBtu for coals having as much as 2.27 lb SO_2 /MMBtu. This sulfur content is representative of the high end of the sulfur content range for Powder River Basin (PRB) coals which are used exclusively at GGS. The evaluated reduction represents a removal efficiency of about 93%. S&L's expectation for a cost effective application of the DSI technology would be at a considerably lower efficiency and a much higher resultant SO_2 emission rate.

From publicly available information, we are aware that a recent BART analysis prepared for Boardman Power Plant contained an evaluation of the use of DSI to lower emissions to 0.4 lb SO_2 /MMBtu subject to the results of pilot testing that would prove or disprove this capability. Also, it should be noted that the Boardman BART analysis for the use of DSI technology represented only 4-6 years of operation prior to closure of the Boardman Plant in the 2018-2020 time frame. This type of analysis criterion will tend to favor low capital and high operating cost technologies such as DSI.

Selection of a target SO_2 emission rate is based in part on the proposed DSI implementation for the Boardman Plant, which burns PRB coal and has a boiler/generating unit of similar size (584 MW) compared to the somewhat larger GGS generating units. The selection of the target SO_2 emission rate is also based in part on published theoretical projections by Solvay, a supplier of Trona and sodium bicarbonate sorbents which are candidate sorbents, for DSI applications. To present a side-by-side comparison of DSI and the FGD options used in the 2008 BART Analysis, we used the same design coal as for the dry and wet FGD options already evaluated as part of the 2008 BART Analysis. Based on the Boardman Plant DSI BART analysis and a very optimistic Solvay projection for control efficiency (approaching 80%) and using the design basis coal for GGS, we have selected an outlet (stack) SO_2 emission rate of 0.36 lb/MMBtu for this assessment. This is a more aggressive removal efficiency than proposed for Boardman where 0.36 lb SO_2/MMBtu would represent a removal efficiency of only 40%. Note that even with this relatively low efficiency for the Boardman BART, Portland General Electric requested flexibility in the ultimate emission limitation dependent on pilot testing. Without extensive GGS-specific modeling and actual field testing, and a contractual performance guarantee from a vendor, the analysis of DSI for GGS presented here must be considered theoretical.

2.2 Selection of Sorbent Type

Sorbents that can be used in the DSI technology include Trona, sodium bicarbonate, or lime. Sodium compounds (Trona and bicarbonate) are more reactive with SO_2 than is lime; therefore lime is rarely evaluated for SO_2 removal in DSI technology applications. Trona is more available than bicarbonate, but bicarbonate is more effective in that a pound of bicarbonate can remove more SO_2 than a pound of Trona. However, bicarbonate is effective in a more limited flue gas temperature range making it less flexible in the dynamic operating condition of a typical power plant. Finally, bicarbonate is more expensive.

Table 1 shows (1) the order-of-magnitude consumption rates for Trona and bicarbonate that would be needed for applications of the technology at GGS, (2) the relative costs of the sorbents, and (3) the domestic supplier's production capacity.

Bicarbonate was not selected as the sorbent of choice for GGS for two reasons. First, bicarbonate needs to be injected into the flue gas stream within a tighter temperature range than Trona which would be a problem for GGS as will be discussed in the section of this report on stoichiometry. Second, GGS would consume such a large portion of the current total market production capability that bicarbonate's availability to GGS would be in question. In addition, there are only three suppliers of bicarbonate so GGS would have little leverage on the suppliers and this situation would result in bicarbonate costs that would very likely escalate at a higher rate than other FGD sorbents, including limestone and lime. For these reasons, sodium bicarbonate is not considered to be an effective sorbent for the GGS units.

Table 1: Comparison of Consumption and Production Capacities for Trona and Bicarbonate

	Trona	**Sodium Bicarbonate**
GGS approximate consumption (million tons/yr)	0.6	0.5
Suppliers' production capacity (million tons/yr)	Solvay = 4.5 FMC = 4.0 Dwight = 4.0 Total = 12.5	Solvay = 0.15 FMC = 0.25 Dwight = 0.35 Total = 0.75
GGSs' consumption as a percent of total suppliers' production capacity*	5%	67%
Price ($/ton)	$145 by rail	$200 by rail

*Assumes the suppliers' production capacity of Trona and Bicarbonate is all available and does not figure in the amount already committed to others.

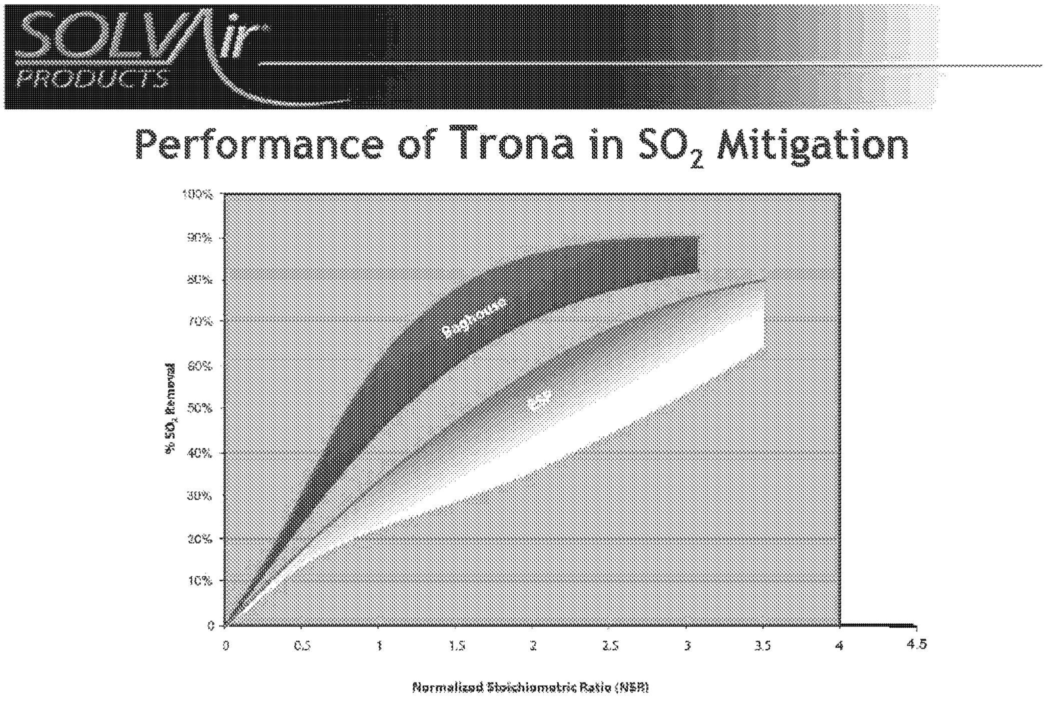
As can be seen from the Table 1, the current production of Trona comes from three suppliers and GGS would be consuming approximately 5% of the market. With only three suppliers competition would be low. This could create a higher rate of escalation in reagent price than what was used in this analysis. For comparison purposes, there are over 21 companies that produce lime (used in FGD technologies) and GGS would consume less than 1% of the lime market.

Trona is the sorbent type selected for this cost analysis.

2.3 Selection of Stoichiometric Ratio

After selection of a sorbent and an emission rate for GGS, the next step was to select a stoichiometric ratio to effectively deal with the selected emission rate. The normalized stoichiometric ratio is defined in the literature and represents the amount of Trona injected to remove a selected amount of SO_2. In the DSI industry, the stoichiometric ratio is correlated to removal efficiency and is usually presented in curves such as that shown in Figure 1. The curve in Figure 1 is publicly available and is presented frequently in DSI literature. However, the curves are very broad, which implies that their accuracy is limited. In other words, the curves show a general relationship between stoichiometric ratio and efficiency, but they are not so accurate that they could be used to define the stoichiometric ratio which would be specifically required at GGS. In addition, the curves are based mainly on industrial plant experience. Industrial plants perform significantly different from utility plants. In S&L's opinion, these curves must be viewed as optimistic projections that should only be used for general information. The only way to develop a meaningful stoichiometric ratio versus efficiency relationship specifically for GGS would be to conduct extensive modeling and field testing at GGS.

Figure 1: Normalized Stoichiometric Ratio versus SO_2 Removal Efficiency (From Solvay)



The relationship between Trona stoichiometric ratio and removal efficiency is highly dependent on the Trona particle size (milled versus un-milled), the flue gas temperature at the Trona injection location, the uniformity of injection across the ductwork, and the time of contact (i.e. residence time). Choosing the stoichiometric ratio is dependent on the aforementioned unit-specific parameters. As noted, the size of the Trona particle impacts the stoichiometric ratio and DSI suppliers have shown in recent tests that smaller, not larger, Trona particle sizes are more effective in capturing SO_2. However, smaller sized Trona particles cannot be shipped over long distances, therefore, the typical method of applying Trona is to deliver un-milled Trona to the site and then process it through an in-line mill that reduces the Trona particle size to about 20-25 microns. S&L used this approach in the GGS cost estimate analysis.

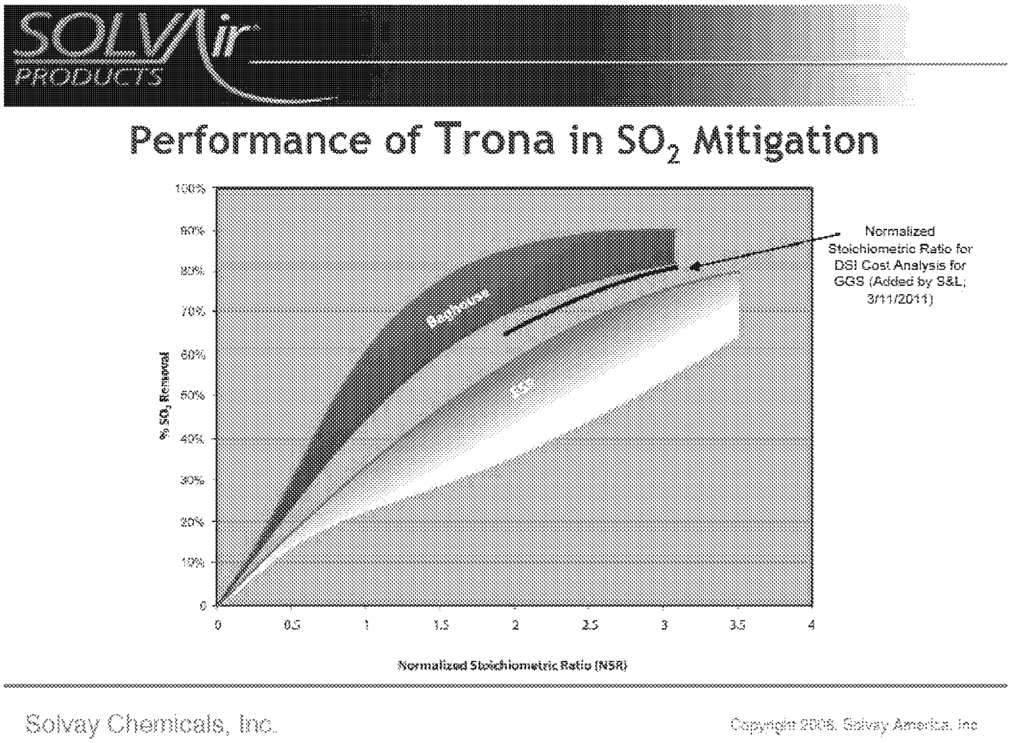
The flue gas temperature at the injection location impacts the stoichiometric ratio. The reaction of Trona relies on the ability of the SO_2 molecules to be captured in the pores of the Trona material. The more porous the material is the more sites that are available to capture SO_2 molecules. Trona has a characteristic that it will calcine ("popcorn") and become more porous when injected at temperatures between 275°F and 800°F. If it is injected at greater than 800°F or below 275°F, then each Trona particle is not as effective, and more Trona is needed, to collect a given amount of SO_2. The temperature profiles at GGS are not ideal (see discussion below) for this situation and, therefore, the Figure 1 curves do not accurately represent the stoichiometric ratio needed at GGS. In S&L's opinion, because much of the experience with this technology comes from industrial scale applications, the removal efficiencies shown by the curves are very optimistic for use at GGS.

Sorbent can be injected upstream or downstream of the unit's air preheaters. The GGS Unit 1 and Unit 2 temperature profiles upstream and downstream of the air preheaters were evaluated to determine the best injection location and the impact of temperature on stoichiometric ratio. The Unit 1 flue gas temperature downstream of the secondary air preheater is below 275°F for 74% of the operating hours. The temperatures upstream of the air heater are determined by the economizer outlet temperature. The Unit 1 economizer outlet temperature is above 800°F for 29% of the operating hours and, if considering greater than 80% load, is above 800°F for 36% of the operating hours. The Unit 2 data indicates the temperature downstream of the secondary air preheater is below 275°F for 100% of the operating hours and the economizer outlet temperature is above 800°F for 25% of the hours. Therefore, both units have a poor temperature profile and the required stoichiometric ratio would be greater than shown in Figure 1 for any removal efficiency.

Finally, because much of the experience with this technology comes from industrial scale applications, the expectation for both removal efficiency and stoichiometry shown on this curve should be considered very optimistic for the large utility boiler systems at GGS.

The stoichiometric ratio relationship selected by S&L for this analysis for the GGS units is shown in Figure 2. This relationship is superimposed over the Solvay curve in Figure 1.

Figure 2: Normalized Stoichiometric Ratio versus SO_2 Removal Efficiency for GGS



2.4 Capital Cost Estimate Determination

The basis of the cost estimates used in this analysis is the same as that used in developing the costs for the 2008 BART Analysis, with one exception: The initial startup date for the technologies is now calendar year 2016 rather than 2013. The costs from the 2008 Analysis and this analysis of the DSI technology have been annualized for startup in 2016 and this change puts all technologies on the same economic basis. This change is necessary to allow time for the dry and wet FGD technologies to be built on an achievable schedule, rather than expecting they could be installed and made operational two years from the present, which is not achievable. The change to the startup date required that the FGD costs be escalated such that the first year of operation is 2016, rather than the 2013. The capital for the DSI technology also uses 2016 as the initial operation date and includes escalation.

The capital costs are presented as several components (construction direct, other construction, indirect, etc…) as shown in Exhibit 1. The DSI application for each Unit is designed for 87,500 lbs/hr (which represents the selected stoichiometry) and includes milling equipment, as previously described.

The direct construction components shown were developed using S&L in-house cost information. The capital cost estimate for the DSI application includes rail unloading, storage, transfer, milling, and injection subsystems. In addition to the DSI system cost estimate information, Exhibit 1 shows direct construction costs for rail upgrades to allow for receiving of Trona on site and includes costs for expanding the ash storage system due to the increased quantity of solid waste from the spent Trona. The rail upgrades and ash storage upgrades were also included in the FGD system cost estimates for the 2008 BART Analysis when appropriate.

The remainder of the capital cost components were added using the same bases that were used for the previously submitted FGD capital costs, with one exception: The contingency for this DSI application capital cost estimate uses 30% contingency (vs. 20% used in the FGD cost estimates) because the DSI order-of-magnitude costs were developed with minimal engineering analysis as compared to the detailed analysis performed for the 2008 BART Analysis.

2.5 O&M Cost Determination

Because it proved not to be practical to develop a true side-by-side comparison of the FGD and DSI technologies for GGS, the O&M costs were developed for a hypothetical case of reducing SO_2 emissions from the design coal used for the 2008 BART Analysis to meet an emission limit of 0.36 lb/MMBtu. This case is hypothetical because: 1) there are no precedents in the electric power industry of application of DSI to a boiler of this size and type, 2) there are no GGS-specific field modeling trials and testing of either Unit which have different designs and different boiler manufacturers, and 3) there are no contractual performance guarantees for GGS. Because it is unknown whether the DSI technology could meet this emission level in the case of GGS, such an application would, by definition, be hypothetical and experimental in nature.

The O&M cost estimate for the DSI implementation as described above is detailed in Exhibits 2a and 2b, and includes the calculation of the first year O&M cost and the annualized O&M cost for each unit, respectively. Consistent with the 2008 BART Analysis, a 20-year amortization period was used for the DSI system. The cost of the reagent and waste disposal are the predominant annual operating costs for the DSI technology. A new landfill cost is included in this evaluation because a new landfill would be needed for the DSI technology waste. The landfill includes costs for site preparation, placement of low permeability soil, installation of a geomembrane, and placement of a protective cover for closure of the landfill.

The DSI application will have an impact on the operation of the baghouse. The significant increase in the solids loading to the baghouse will require the bags to be cleaned more frequently. Bag cleaning frequency has a direct impact on the life of the bag. The increased cleaning frequency will lessen the bag life by 10% to 20%.

2.6 Annualized Cost Determination

Exhibit 3 presents the annualized costs for the FGD technologies as presented in the 2008 BART Analysis. As previously addressed, these costs were based on a 2013 operating date which is no longer reasonable. Therefore, Exhibit 3 also presents the same FGD costs escalated to calendar year 2016 to accommodate a normal engineering, construction and startup schedule. The exhibit also includes the DSI cost estimates for each option considered escalated to 2016.

The data in Exhibit 3 is close to the side-by-side comparison that NDEQ requested, but is based on a DSI outlet SO_2 emission rate of 0.36 lb SO_2 /MMBtu, not the 0.15 lb SO_2 /MMBtu value used for FGD technologies. Evaluating the DSI technology at an outlet loading of 0.15 lb SO_2/MMBtu and a corresponding SO_2 removal of 91% would represent an extrapolation of available data well beyond practicality. Even when evaluated at a lower removal efficiency and a higher outlet loading, the DSI technology annualized cost ($/yr) and normalized cost ($/ton SO_2) is higher than the FGD cost from the 2008 BART Analysis.

3.0 Other Retrofit Impacts

3.1 Energy Usage

The DSI application is expected to consume about 0.1 kW of the station's power for every 1 lb/hr of sorbent feed. For both units at full capacity, this equates to 16 MW, which is 1.2 % of the stations gross capacity. Most of the power is consumed by pneumatically handling the Trona, cooling the transport air, and keeping the stored Trona dry. The dry and wet FGD technologies consume 1.9 % and 2.7 %, respectively, of the station's gross power.

3.2 Disposal of Liquid

The DSI application does not use water to improve the mass transfer of SO_2 as is the case with dry and wet FGD technologies. The FGD technologies consume between 1,700 and 2,200 gpm of water.

Some water is used in DSI application to wash the Trona mills as a part of required daily maintenance. The Trona mills are filled with water to dissolve the deposits of sodium that accumulate on the mill internals. The water used for this purpose averages less than 10 gpm on an annual basis. The resulting liquid waste is high in sodium and, therefore, must be properly disposed of.

3.3 Potential Fugitive Emissions

The DSI application will have the potential to generate fugitive emissions as the dry sorbent is pneumatically transferred from the rail cars to the storage silos, from the storage silos to the day silo, and from the day silo to the injection subsystems. In addition, the rail delivery generates fugitive emissions while the sorbent is in transit. Finally, the handling of the baghouse waste streams have the potential to generate fugitive emissions as they are pneumatically transferred to the waste silos and unloaded to haul trucks. Also, since the solid waste generation rate associated with the DSI application will be about 3 times the current solid waste quantity, there will be three times the amount of haul truck traffic which will also increase fugitive emissions. All of these solids handling systems have the potential to increase fugitive dust emissions and must be controlled with additional dust control hardware and systems which increase both the capital requirement and O&M requirement.

4.0 Conclusion

It remains S&L's judgment that the DSI technology has not been proven on any power plant the size of the GGS units and, therefore, should not be considered "technically feasible" as the term is defined in the Regional Haze rule. Even so, as requested by NPPD, S&L developed the cost estimates for the application of the DSI technology on both GGS units to be as close to a side-by-side comparison to the previously analyzed dry and wet FGD technologies as is practical and reasonable.

Although the initial capital requirement for a DSI system at GGS is considerably less than that required for either of the FGD technologies evaluated in the 2008 BART Analysis, the operating costs for the DSI system at GGS, over the 20 year amortization life, resulted in an annualized cost of nearly 34% greater for the DSI system. Also, the cost to capture a ton of SO_2 with the DSI system is over twice as expensive as that required with either of the FGD technologies evaluated in the 2008 BART Analysis.

Nebraska Public Power District
Gerald Gentleman Units 1&2

EXHIBIT 1
Dry Sorbent Injection Capital Cost

Project No. 12681-002
March 11, 2011

	GGS Unit 1	GGS Unit 2
Construction Direct		
Rail Unloading, Tracks and Switches	$ 1,995,000	$ 1,995,000
New Waste Silos	$ 4,676,000	$ 4,676,000
DSI System	$ 35,960,000	$ 35,960,000
Other Construction		
Engineering and Construction Management (5%)	$ 2,132,000	$ 2,132,000
Per Diem, Premium (5%)	$ 2,132,000	$ 2,132,000
Profit (10%)	$ 4,690,000	$ 4,690,000
EPC Fee (20%)	$ 10,317,000	$ 10,317,000
Total Construction	$ 61,902,000	$ 61,902,000
Indirect		
Owners Engineer	$ 500,000	$ 500,000
Bond Fees (2.5% of first $200,000,000)	$ 2,500,000	$ 2,500,000
Owners Cost (2%)*	$ 2,944,000	$ 2,944,000
Escalation	$ 5,091,000	$ 5,091,000
Sales Tax (5.5% equip/material)	$ 1,362,000	$ 1,362,000
Contingency (30%)	$ 21,882,000	$ 21,882,000
Total Project Cost	$ 96,181,000	$ 96,181,000
AFUDC	$ 7,984,000	$ 7,984,000
GRAND TOTAL COST ($2016)	$ 104,165,000	$ 104,165,000

Notes:
* Includes 2 weeks of sorbent injection testing.

Nebraska Public Power District
Gerald Gentleman Units 1&2

EXHIBIT 2A
Budgetary DSI O&M Cost Estimate (per Unit)

Project No. 12681-002
March 11, 2011

Dry Sorbent Type		**Trona**
Design Removal Efficiency		**80% SO_2 Removal**
Particulate Collector		**Baghouse**
Input Data for System Analysis:		
Fuel		PRB
Gross Capacity	MW	745
Capacity Factor	%	80
Heat Input to Boiler at Full Load	MMBtu/hr	7,047
Fuel Heating Value	Btu/lb	8,124
Fuel Sulfur Content	lb/MMBtu	1.72
Fuel Ash Content	%	5.42
Ash Removal in Boiler	%	30.00
Dry Sorbent Injection Analysis:		
Dry Sorbent Requirement	lb/hr	87,500
Dry Sorbent Requirement	t/yr	383,250
Dry Sorbent Consumption	lb/hr @ CF	70,000
Dry Sorbent Consumption	t/yr @ CF	306,600
Waste Disposal Analysis:		
Flyash Production (Leaving the Boiler)	lb/hr	32,910
Sorbent Waste Rate	lb/hr	67,495
Total Waste for Disposal (Ash + Sorbent)	lb/hr	100,405
Total Waste for Disposal (Ash + Sorbent)	t/yr	439,775
Total Waste for Disposal (Ash + Sorbent)	t/yr @ CF	351,820
Auxiliaries Analysis:		
Increase in Auxiliary Power Consumption - Full Load	kW	8,750
Economic Parameters:		
Total number of Bags		16,474
Replacement Bag Cycle	years	6
Bag Replacement Cost	$/bag	172.00
Dry Sorbent Cost	$/t	145.00
Waste Disposal Cost	$/t	5.64
Revenue from Flyash Sale	$/t	1.35
Power: Energy Charge (Auxiliary Power)	$/MWh	45.65
Power: Capacity Charge	$/kW/year	46.00
Labor Rate	$/hr	40.60
Variable O&M Cost:		
Bag Replacement Cost	$/yr	$ 473,000
Dry Sorbent Cost	$/yr	$ 44,457,000
Waste Disposal Cost	$/yr	$ 1,984,000
Revenue from Flyash Sale	$/yr	$ -
Power: Energy Charge Cost (Auxiliary Power)	$/yr	$ 2,800,000
Power: Capacity Charge	$/yr	$ 402,500
SO2 Allowance Sale	$/yr	$ (1,016,000)
Total Estimated Variable O&M Cost	**$/yr**	**$ 49,100,500**
Fixed O&M Cost		
Additional Operating labor	no.	4.5
Additional Operating labor	$/yr	$ 382,000
Additional Maintenance Material	$/yr	$ 240,000
Additional Maintenance Labor	$/yr	$ 360,000
Additional Administrative labor	$/yr	$ -
Total Estimated Fixed O&M Cost	**$/yr**	**$ 982,000**

Nebraska Public Power District
Gerald Gentleman Units 1&2

EXHIBIT 2B
Budgetary DSI Annualized O&M Cost Estimate

Project No. 12681-002
March 11, 2011

Dry Sorbent Type	**Trona**
Design Removal Efficiency	**80% SO_2 Removal**
Particulate Collector	**Baghouse**

Annualized Variable O&M Cost:		
Bag Replacement Cost	$/yr	$ 578,000
Dry Sorbent Cost	$/yr	$ 54,238,000
Waste Disposal Cost	$/yr	$ 2,421,000
Revenue from Flyash Sale	$/yr	$ -
Power: Energy Charge Cost (Auxiliary Power)	$/yr	$ 3,416,000
Power: Capacity Charge	$/yr	$ 492,000
SO2 Allowance Sale	$/yr	$ (1,240,000)
Total Estimated Annualized Variable O&M Cost	**$/yr**	$ 59,905,000
Annualized Fixed O&M Cost:		
Additional Operating labor	$/yr	$ 467,000
Additional Maintenance Material	$/yr	$ 293,000
Additional Maintenance Labor	$/yr	$ 440,000
Additional Administrative labor	$/yr	$ -
Total Estimated Annualized Fixed O&M Cost	$/yr	$ 1,200,000
TOTAL ESTIMATED ANNUALIZED O&M $2011	$/yr	$ 61,105,000
TOTAL ESTIMATED ANNUALIZED O&M TO 2016$	$/yr	$ 69,135,000

Nebraska Public Power District
Gerald Gentleman Units 1&2

EXHIBIT 3
Modification of Table 4 from 2008 BART Analysis, SO2 Cost of Compliance

Project No. 12698-002
March 11, 2011

Technology Options

Description	Dry FGD	Wet FGD	Dry Sorbent Injection
Emission Rate (lb/MMBtu)	0.15	0.15	0.36
Emission Reduction (tpy)	39,815	39,815	25,857
Capital Costs ($)	$ 981,592,000	$ 1,029,819,000	
Annualized Capital Cost ($)	$ 80,013,000	$ 83,965,000	
Annualized Operating Cost ($)	$ 27,806,000	$ 24,485,000	
Annnualized Outage Cost ($)	$ 698,000	$ -	
Total Annualized Cost ($)	$ 108,517,000	$ 108,450,000	
Normalized Cost ($/ton SO2 reduced)	$ 2,726	$ 2,724	
Eacalation factors to convert the above Table 4 to the below revised Table 4			
Capital Escalation Rate (%)	2.5%	2.5%	
O&M Escalation Rate (%)	2.5%	2.5%	
Years of Escalation (#)	3	3	
Theoretical Normalized Stoichiometric Ratio			3.0
The above Table 4 but Escalated to 2016 1st year operating date (total for both Units)			
Emission Rate (lb/MMBtu)	0.15	0.15	0.36
Emission Reduction (tpy)	39,815	39,815	25,857
Capital Costs ($)	$ 1,057,068,000	$ 1,109,003,000	$ 208,330,000
Annualized Capital Cost ($)	$ 86,166,000	$ 90,422,000	$ 17,500,000
Annualized Operating Cost ($)	$ 29,945,000	$ 26,368,000	$ 138,270,000
Annnualized Outage Cost ($)	$ 752,000	$ -	$ -
Total Annualized Cost ($)	$ 116,863,000	$ 116,790,000	$ 155,770,000
Normalized Cost ($/ton SO2 reduced)*	$ 2,935	$ 2,933	$ 6,024

* Calculated based on the maximum actual 24-hour SO2 emissions realized over the 3-year baseline period (2001-2003) that was used in the 2008 BART Analysis.

APPENDIX B

APPENDIX B

Gerald Gentleman Station
Modeling Scenarios for BART Analysis (Added DSI scenario in gray)

Control Description			2-Unit Hrly Maximum 24-h avg. actual heat input*	2-unit avg SO2 E.F.	2-unit avg NOx E.F.	2-unit avg Filterable** PM E. F.	TOTAL Emissions Both Units				Stack Parameters***	
SO2	NOx	PM	(MMBtu/hr)	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	SO2 (g/sec)	NOx (g/sec)	PMC (g/sec)	PMF (g/sec)	Temp. (deg. K)	Vel. (m/sec)
no control	no control	FF	15175.5	0.749	0.455	0.00823	1412.87	869.51	6.14	35.11	417.05	22.31
no control	LNB/OFA	FF	15175.5	0.749	0.23	0.00823	1412.87	439.79	6.14	35.11	417.05	22.31
DSI	*none*	*FF*	*15175.5*	*0.36*	*0.455*	*0.00823*	*688.36*	*869.51*	*6.14*	*35.11*	*417.05*	*22.31*
SDA	LNB/OFA	FF	15175.5	0.15	0.23	0.00823	286.82	439.79	6.14	35.11	352.04	20.48
SDA	LNB+SCR	FF	15175.5	0.15	0.08	0.00823	286.82	152.97	6.14	35.11	352.04	20.48
SDA	none	FF	15175.5	0.15	0.455	0.00823	286.82	869.51	6.14	35.11	352.04	20.48
no control	LNB/OFA+SCR	FF	15175.5	0.749	0.08	0.00823	1412.87	152.97	6.14	35.11	417.05	22.31

* Maximum daily heat input for baseline period, occurring in 2001. "No-control" SO2 and NOx emission factors are estimated values for maximum 24-hour emission days.
** Filterable emission factor based on stack tests after FFs installed.
*** Slightly more conservative (lower) velocity of the two stacks to be used in the modeling.
Condensable PM emissions assumed to be 0.014 lb/mmBtu, based on AP-42 and 0.44% sulfur, and are assumed to form only PMF.
PMC for fabric filter is 39% of total filterable PM, per AP-42
PMF for fabric filter is 53% of total filterable PM plus 0.014 lb/mmBtu condensables, per AP-42